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ENGINEERING MODEL DEVELOPMENT OF SELECTED RESERVOIR HETEROGENEITIES IN BELL CREEK FIELD UNIT A

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ABSTRACT

Based on geological and production data, an initial improved engineering model of the barrier island Muddy formation deposit at Bell Creek oilfield, Montana and the important geological heterogeneities encountered in a four section area in Unit 'A' of the reservoir were constructed. In the geological model of the reservoir, the barrier island payzone thickness varies from its maximum value of over 20 ft in the center of the deposit to less than 2 ft at the eastern and western edges. There are drastic variations in both permeability and porosity values in the area investigated, and this variation is more pronounced from the center of the deposit to the edges. Because of their similar porosity and permeability distributions and log signatures, two facies (upper shoreface and foreshore) of the barrier island deposit have been grouped into a single flow unit.

Production performance analysis for Bell Creek field indicates that the main heterogeneities affecting the fluid flow in this barrier island/valley fill complex are location and geometry of the valley incisions, stacking patterns of facies with highly variable permeability values, areas of low permeability due to high clay content, and faults.

Simulations and single-well history matching of primary oil and gas production have been used to define more accurately fluid and rock-fluid parameters used in the simulator input file where field data were insufficient for rigorous simulation. Although acceptable matches have been obtained, more accurate data are needed regarding actual permeability to reservoir fluids (instead of gas permeability), relative permeabilities, and bottomhole pressure to improve the usefulness of simulations as tests for the accuracy of the reservoir model. Research in some of these areas of investigation is proposed in the FY88 research plan.

ACKNOWLEDGMENT

The contribution of Jeff Knight, consultant, in running the simulation is acknowledged.

INTRODUCTION

The broad objective of the NIPER geoscience research program is to develop a methodology to determine the effect of various heterogeneities in a barrier island deposit in controlling the movement and trapping of oil. The geological model of the reservoir built with information extracted from cores, logs, and analogous outcrops is being used in constructing an engineering model of the reservoir. By comparing the results of simulations performed on the engineering model with actual field data, conclusions can be drawn about the adequacy of the engineering model and about the effect of various reservoir heterogeneities on oil production.

The preliminary geological model of Bell Creek reservoir in Sections 22, 23, 26, and 27 in Unit 'A' gives an identification and estimate of the lithostratigraphy, petrophysics, and stacking patterns of the various geological facies within the reservoir. The geological heterogeneities which have the greatest effect on fluid flow in the reservoir appear to be the result of changes in geometry of the barrier island/valley fill complex, stacking patterns of multifacial productive, potentially productive and nonproductive zones, internal architecture of barrier island deposits with emphasis on clay distribution, diagenetic alterations, and blocking and faulting of the entire Muddy formation.[1]

GEOLOGICAL-ENGINEERING MODEL

Geology

The producing sandstone in the Unit A, Bell Creek field, Montana (Fig. 1) is part of the Lower Cretaceous Muddy formation. It is composed of two genetically different major sandstone reservoir units interpreted as (a) barrier islands (littoral marine bars), and (b) valley fills. The entire producing sandstone is underlain by Skull Creek shale and overlain by Shell Creek/Mowry shale.

The oil productivity in Bell Creek, Unit A is affected by at least four geological factors:

(1) architecture of the barrier island facies (stacking and lateral extent of various facies);

(2) distribution and type of diagenesis (clay, compaction);

(3) relative location of valley fill deposits and the barrier sandstone deposit; and

(4) local faulting.

Reservoir Framework

A structure contour map on the top of the barrier island sandstone (Fig. 2) shows a general northwest dip at a 90 to 100 ft/mile rate. The isopach map (Fig. 3) shows a maximum thickness of the deposit to be about 29 ft in the central part of the four-section area under study. The thickness gradually decreases toward the southeast and northwest.

The flexures in the contour lines drawn on the top of the sandstone complex in both maps indicate either possible faulting or valley incisions, or both. The flexures at the western extremity of reservoir boundary are generally interpreted as deep valley cuts (Fig. 3).

Variations in the stratigraphy of the barrier island facies are indicated in the two stratigraphic cross-sections AA' and BB' (locations shown in Fig. 1) using gamma ray logs (Fig. 4) and core data. The gamma ray and sonic logs were calibrated using core-derived facies interpretations. Cross section AA' is parallel to, and the cross-section BB' is perpendicular to, the depositional strike of the barrier island deposit. In these cross-sections, the variations in the thicknesses of foreshore, uppershoreface, and lowershoreface facies are indicated. The foreshore and uppershoreface facies in these cross-sections have similar core-plug derived horizontal permeability and porosity distributions and similar log signatures; therefore these facies have been grouped into a single flow unit.

Cross section AA' indicates that the thickness and the reservoir quality of the barrier island sandstone improves from southwest to northeast near the central part of the barrier deposit. Good reservoir quality and high rates of oil production in well P2 are due to the massive and crossbedded sandstones in the upper shoreface and foreshore facies, respectively.

In well C-8, the facies development and the related sedimentary structures within the barrier are generally comparable to those encountered in well P2, but the reservoir quality of the sandstone is reduced because of the larger proportion of silt and clay. Further southwest, in the well 27-14 area, the reservoir quality is diminished further mainly because of the higher percentage of clay cementation.

Rock Properties

Cross sections AA' and BB' (Fig. 4) show evidence of strong permeability stratification resulting from various reservoir heterogeneities. Permeability variations along these two sections suggest that the low-permeability streaks are rather limited in lateral extent and do not subdivide the foreshore and uppershore face facies of the barrier sandstones into separate flow units.

A partial map of the geometric means of air permeability distributions in the four-section area under study is shown in figure 5. This map indicates that the mean permeabilities decrease from the center toward both the eastern and western edges of the bar.

The porosity map shown in figure 6 was derived using 51 density logs. It shows zones with highest porosities near the axial position and slightly east of it in the barrier island deposit.

The sharp changes in contour patterns in figures 2, 3, and 6 in the extreme northern parts of Sections 26 and 27 could be due to a northwest, southeast trending fault if the structural map drawn on the base of Muddy formation would follow a similar pattern.

Reservoir Fluids and Rock-Fluid Properties

Data on fluids and rock-fluid properties for reservoir simulation were obtained using (1) measured values from published reports[2-3] and (2) correlation formulas.[4] These were further refined by matching the primary gas production in the BOAST single-well simulation using oil rates specified for selected wells. A three-layer model with 7x7x3 ft gridding and completed only in the lower part of the payzone (in agreement with well completion records) gave the best agreement with the field production data, as shown in figure

7. Nevertheless, the simulations show an excess of gas production, which requires a better determination of the gas-fluid relative permeability. Using actual liquid permeability values instead of air permeability values is also expected to improve the agreement of field data and simulation results.

A copy of the input data file is displayed in table 1, and the nomenclature of the various terms is presented at the end of the table.

SUMMARY AND CONCLUSIONS

1. An initial improved engineering model of Bell Creek reservoir in Sections 22, 23, 26, and 27 has been constructed.

2. The heterogeneities which most affect the fluid flow are barrier island facies distributions; valley incisions into the top of the barrier filled with continental and marine, non-barrier deposits; and probable faults.

3. Further core and log analyses from both reservoir and outcrop are needed to locate more accurately the valley fills.

4. Single-well simulations were used in history matching to refine the rock and fluid parameters when measurements were too few or unavailable.

5. In specific locations where production or well test data indicate the possible existence of faults or low-permeability regions, multiwell simulations are needed to define the influence of these heterogeneities on fluid flow in the reservoir.

6. More and/or better reservoir pressure data, relative permeability data, and permeability to reservoir fluids data are needed to improve increase the accuracy of simulation predictions and to improve the effectiveness of using simulation as a tool to verify the geological/engineering model of the reservoir.

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TABLE 1. - Rock Fluid Properties

SAT	KRO	KRW	KRG	PCOW	PCGO
0.1	0.0	0.0	0.0010	10.0	0.5
0.12	0.0	0.0	0.0050	10.0	0.6
0.16	0.0	0.0	0.0060	10.0	0.8
0.20	0.0	0.0	0.0090	10.0	1.0
0.30	0.0	0.0	0.0100	8.75	1.5
0.40	0.0501	0.0334	0.0200	7.50	2.0
0.50	0.1503	0.0668	0.0300	6.25	2.5
0.60	0.3169	0.1000	1.0000	5.00	3.0
0.70	0.6000	0.1168	1.0000	3.75	3.5
0.80	1.0000	0.1336	1.0000	2.50	4.0
0.90	1.0000	0.1419	1.0000	1.25	4.0
1.00	1.0000	0.1503	1.0000	0.00	4.0

PBO	VSLOPE	BSLOPE	RSLOPE	PMAX	IREPRS
1204.7	0.0003239	-0.000007683	0.0	1614.7	0

P	MUO	BO	RSO
14.7	8.9547	1.03026	1.0
214.7	7.2696	1.04100	24.0
414.7	5.8269	1.05501	54.0
614.7	4.8325	1.06949	85.0
814.7	4.0714	1.08536	119.0
1014.7	3.4920	1.10218	155.0
1204.7	3.07303	1.11852	190.0
1414.7	2.7016	1.13717	230.0
1614.7	1.4201	1.15542	269.0

P	MUW	BW	RSW
14.7	0.6181	1.00777	0.0
214.7	0.6181	1.00716	0.0
414.7	0.6181	1.00653	0.0
614.7	0.6181	1.00588	0.0
814.7	0.6181	1.00522	0.0
1014.7	0.6181	1.00453	0.0
1204.7	0.6181	1.00387	0.0
1414.7	0.6181	1.00311	0.0
1614.7	0.6181	1.00237	0.0

P	MUG	BG	CR
14.7	0.0120	0.1007E+01	0.300E-05
214.7	0.0121	0.7311E-01	0.300E-05
414.7	0.0123	0.3694E-01	0.300E-05
614.7	0.0126	0.2433E-01	0.300E-05
814.7	0.0129	0.1793E-01	0.300E-05
1014.7	0.0133	0.1408E-01	0.300E-05
1204.7	0.0138	0.1163E-01	0.300E-05
1414.7	0.0143	0.9721E-02	0.300E-05
1614.7	0.0149	0.8390E-02	0.300E-05

RHOSCO	RHOSCW	RHOSCG
53.6640	62.2380	0.0400

NOMENCLATURE

SAT = fluid saturation (fraction)
KRO = oil phase relative permeability (fraction)
KRW = water phase relative permeability (fraction)
KRG = gas phase relative permeability (fraction)
PCOW = oil/water capillary pressure (psi)
PCGO = gas/oil capillary pressure (psi)
PBO = initial oil bubble point pressure (psia)
VSLOPE = slope of the oil viscosity vs pressure for undersaturated oil (cp/psi)
BSLOPE = slope of the oil formation volume factor vs pressure for under saturated oil (RB/STB/psi)
RSLOPE = slope of the solution gas-oil ratio vs pressure for undersaturated oil (SCF/STB-psi)
PMAX = maximum pressure entry in tasks (psia)
P = pressure (psia)
MUO = saturated oil viscosity (cp)
BO = saturated oil formation volume factor (RB/STB)
RSO = saturated oil gas-oil ratio (SCF/STB)
MUW = water viscosity (CP)
BW = water formation volume factor (RB/STB)
RSW = water solution gas-water ratio (SCF/STB)
MUG = gas viscosity (CP)
BG = gas formation volume volume factor (RCF/SCF)
CR = rock compressibility (psi^{-1})
RHOSCO = stock tank oil density (lb/ cu ft)
RHOSCW = stock tank water density (lb/cu ft)
ROSCG = gas density at standard conditions (lb/cu ft)

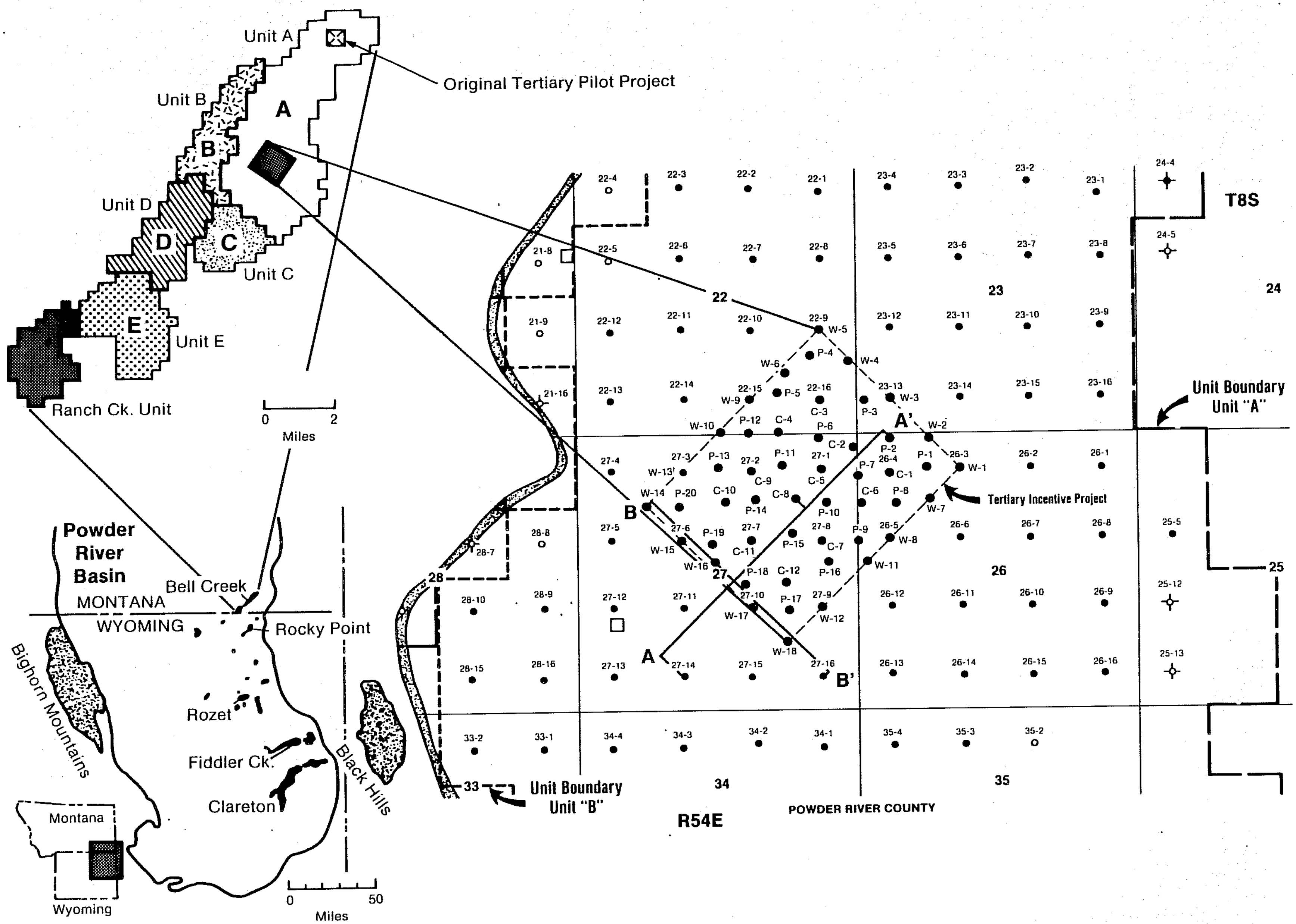

FIGURE 1. - Index map shows units comprising Bell Creek field and well control. P, production wells; W. water injection wells; and C, chemical injection wells.

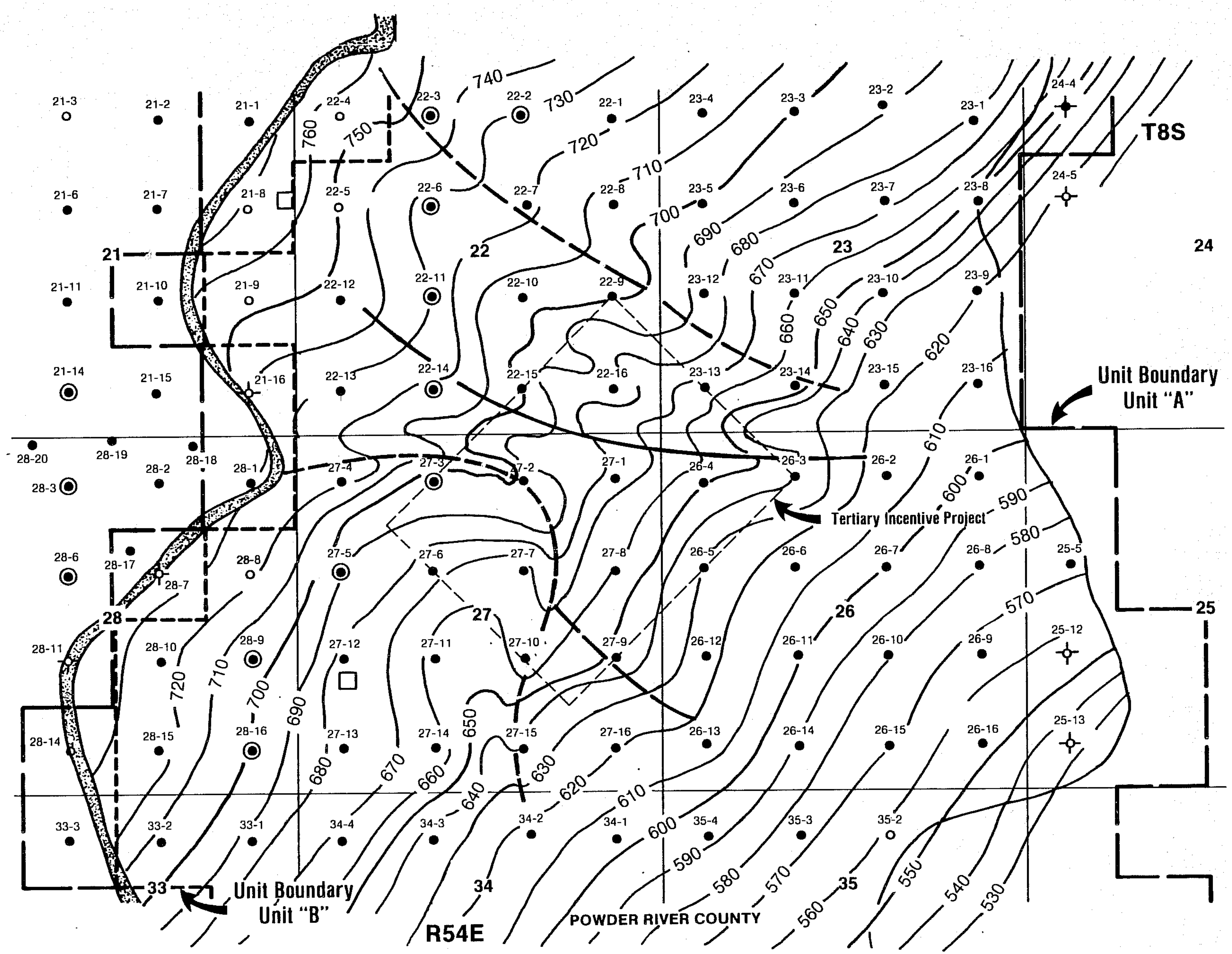

FIGURE 2. - Structural contours (in feet below M.S.L.) on the top of the barrier island sandstones. C.I. = 10 feet. Locations of possible faults and valley incisions are indicated by solid and dashed lines, respectively.

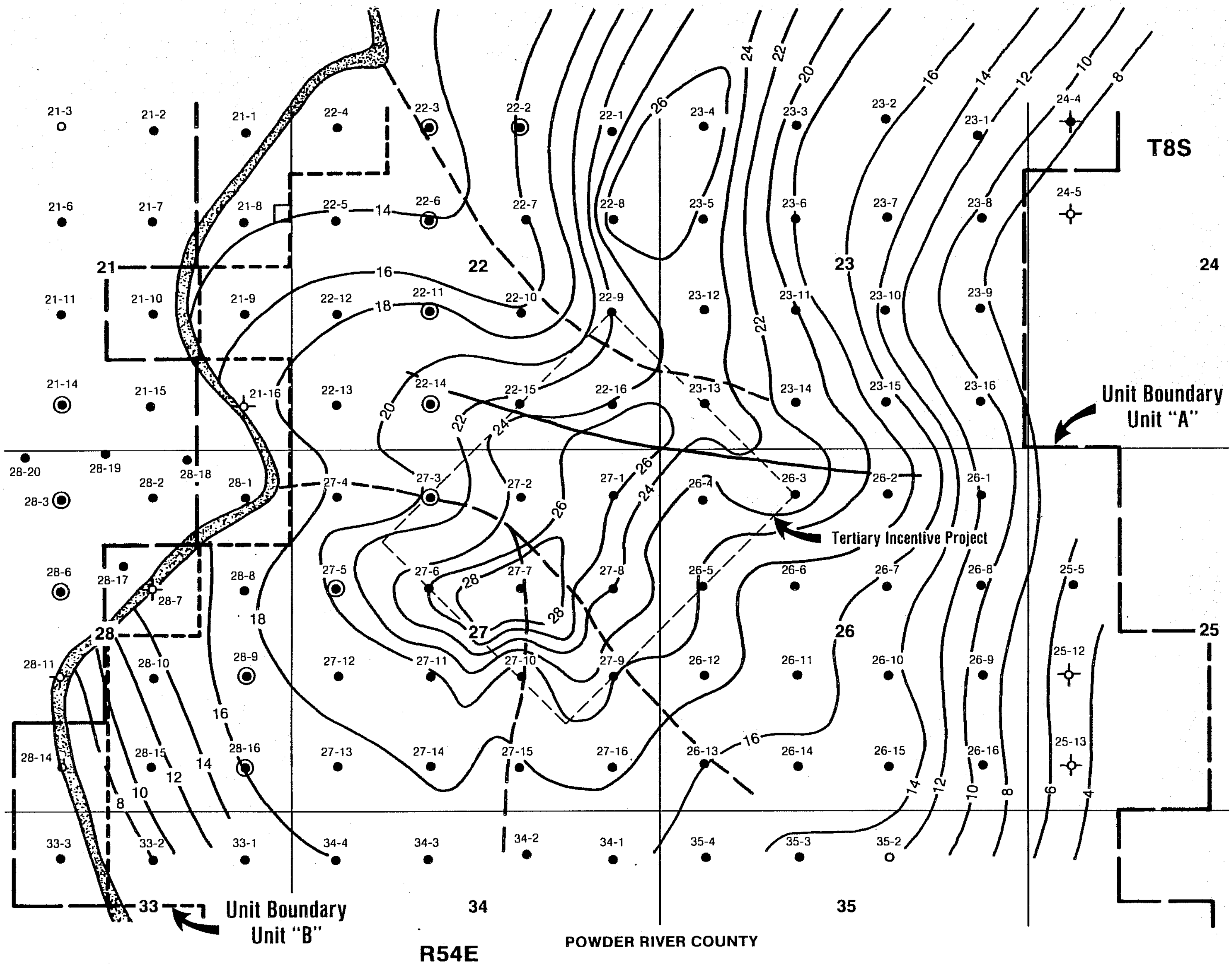

FIGURE 3. - Isopach map of the barrier island sandstones in thes study area. C.I. = 10 ft. Locations of possible faults and valley incisions are indicated by solid and dashed lines, respectively.

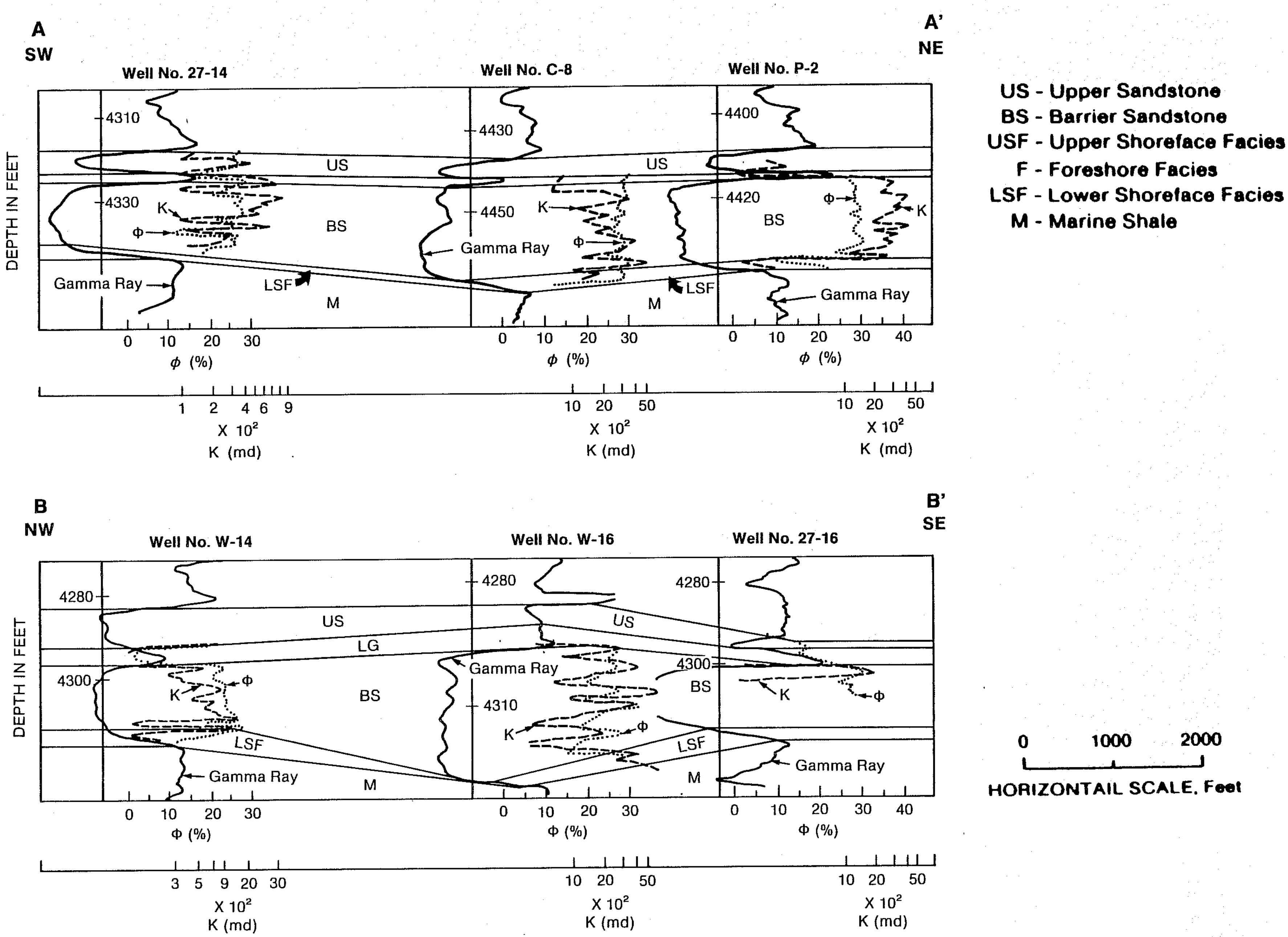

FIGURE 4. - Stratigraphic cross-sections parallel (AA') and perpendicular (BB') to the depositional strike of the bar. See figure 1 for location of cross-sections.

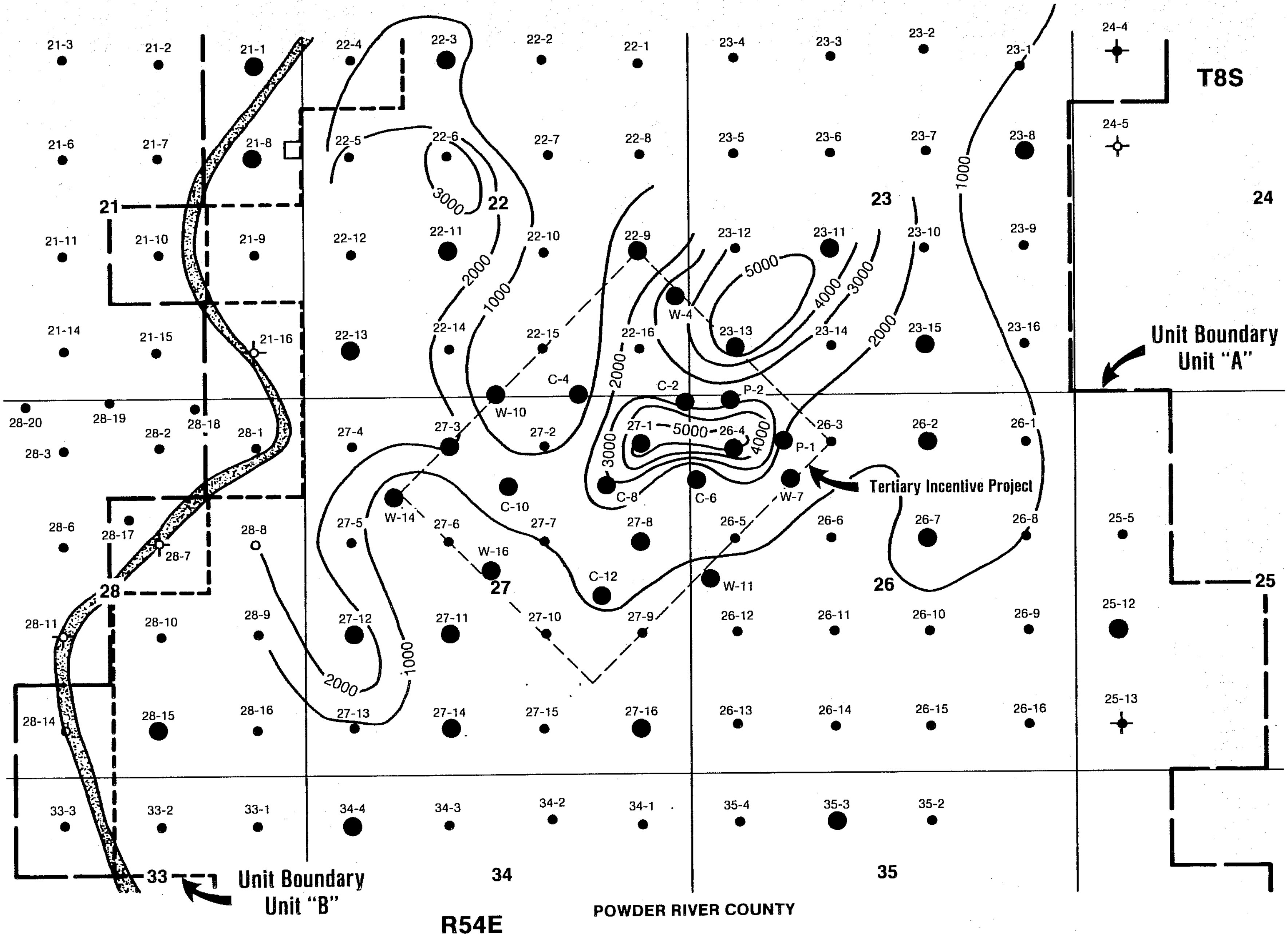

FIGURE 5. - Distribution of geometric means of the air permeability data for wells in the study area. C.I. = 1,000 md. Wells with permeability data are indicated by large circles.

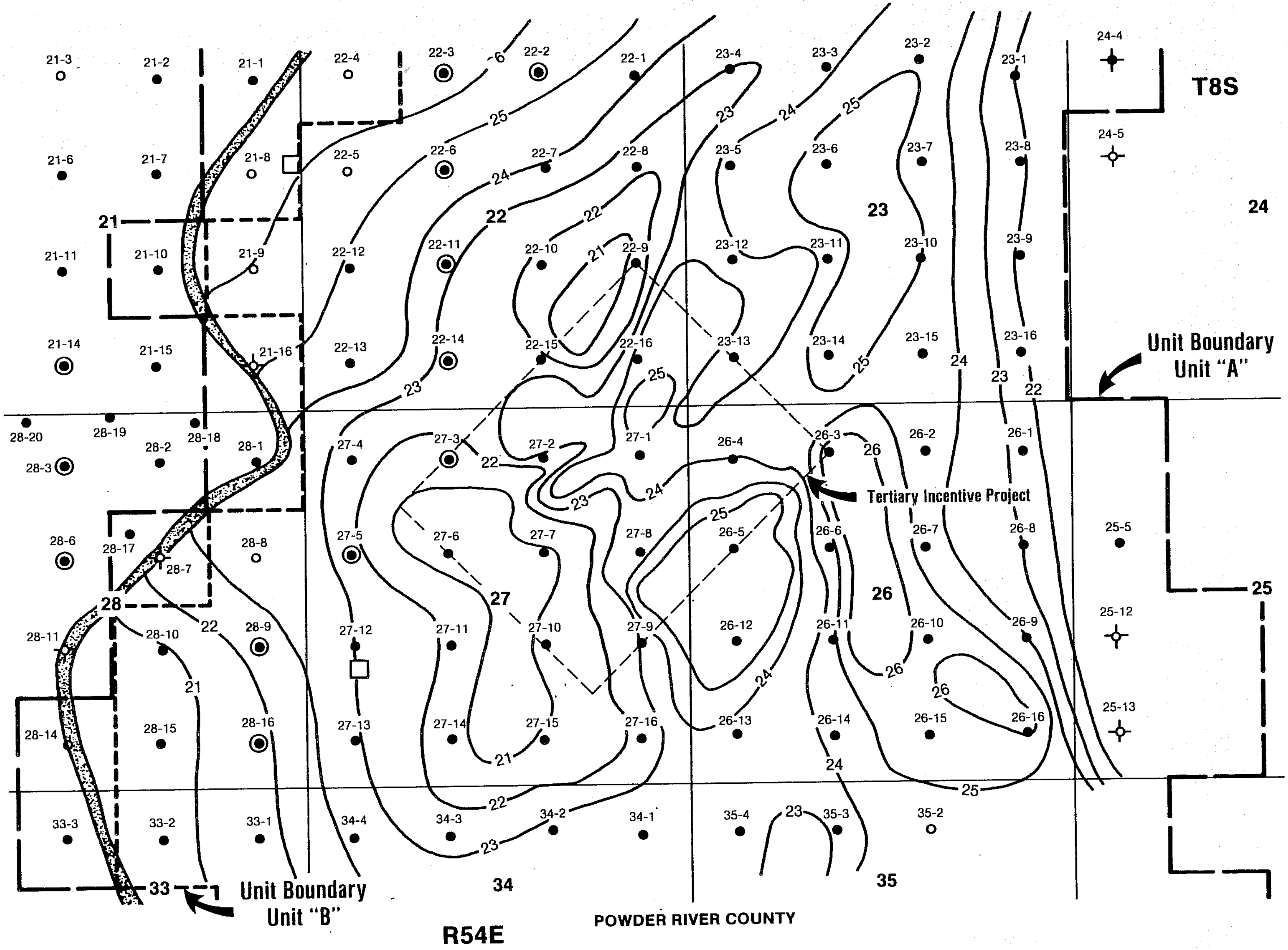

FIGURE 6. - Average log-derived porosities (in percentage) of the barrier island sandstones in the study arkea.

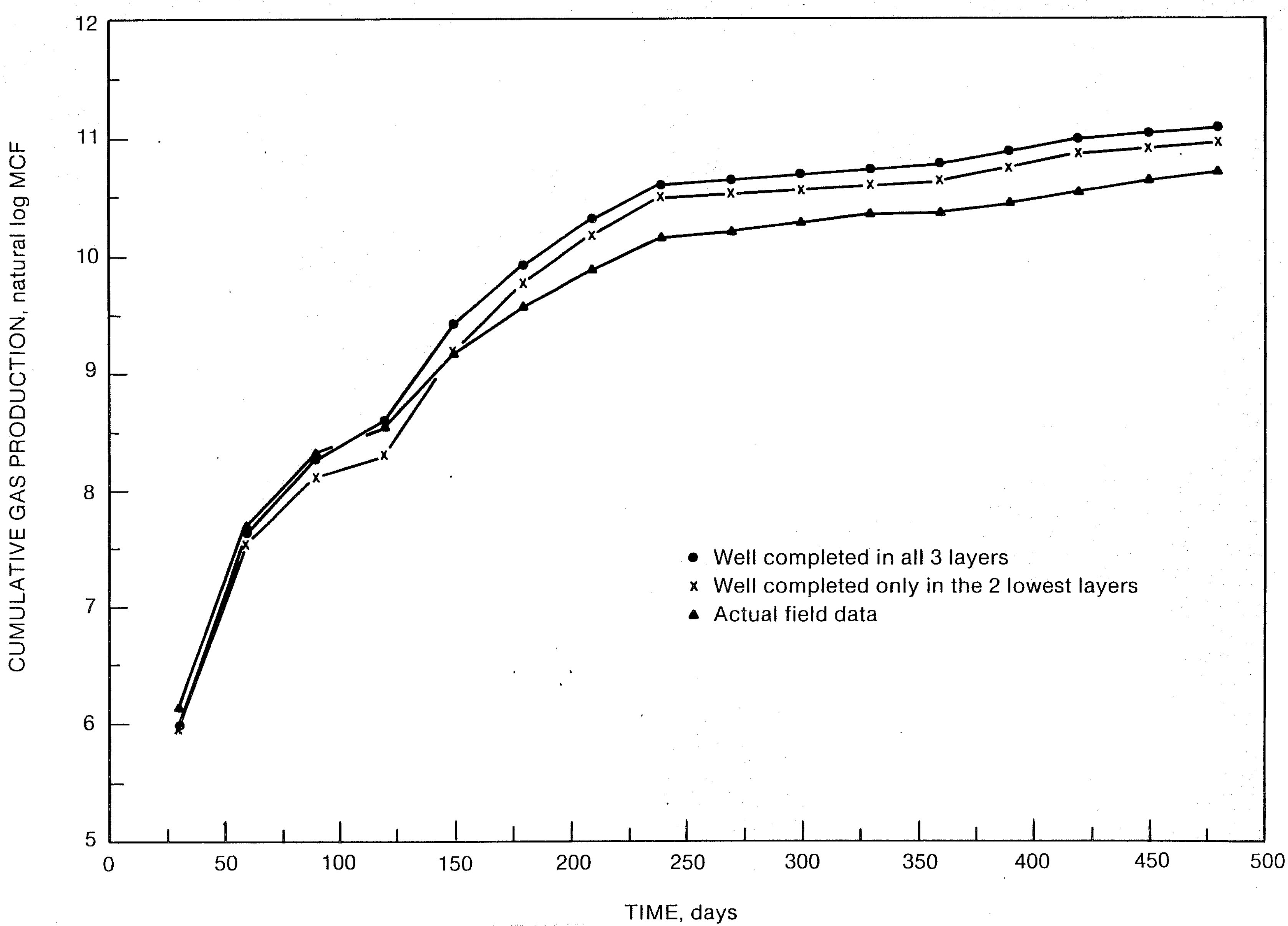

FIGURE 7. - Comparison of actual and predicted cumulative gas production in single-well simulations.